TECHNICAL REVIEW DOCUMENT
For
RENEWAL of OPERATING PERMIT 96OPMR129

Public Service Company – Pawnee Station
Morgan County
Source ID 0870011

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Revised March, May and September 2009

I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewal and modification to the Operating Permit proposed for this site. The original Operating Permit was issued January 1, 2003. The expiration date for the permit was January 1, 2008. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. After submittal of the renewal application, the source submitted an application on December 19, 2008 to revise their permit to incorporate the mercury requirements in Colorado Regulation No. 6, Part B, Section VIII. The Division considers that this modification must be processed as a significant modification. A significant modification is processed under the same procedures as a renewal, i.e. it must go through a 30-day public comment period and EPA 45-day review period. Therefore, since the renewal application has been submitted the Division is incorporating the modification with the renewal.

This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted November 20, 2006, the modification application submitted on December 19, 2008, comments on the draft permit and technical review document received on May 7, 2009, additional information submitted on May 14 and 28, 2009, comments received on July 3, 2009 during the public comment period, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this Operating Permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This Operating Permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this Operating Permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

This facility consists of one (1) coal-fired boiler (Unit 1) used to produce electricity. This boiler and turbine generator is rated at 547 gross MW and is equipped with a baghouse to control particulate matter emissions and low NO_X burners with over-fire air to control NO_X emissions. In addition, there is natural gas-fired auxiliary boiler (Unit 2) at the facility, which is primarily used to provide heat to the facility when Unit 1 is not running. Other significant emission sources at this facility consist of fugitive particulate matter emissions from coal handling and storage, ash handling and disposal and vehicle traffic on paved and unpaved roads. In addition, there are also sources of particulate matter emissions from point sources, including coal handling (crushers, transfer towers and conveying), ash handling (ash silo), and the soda ash handling system (for water treatment system). The facility also has one cooling tower that emits particulate matter emissions in "drift" and evaporates chloroform. In December 2008, the source submitted an application to incorporate the mercury limits from Colorado Regulation No. 6, Part B, Section VIII into their permit. In order to meet the mercury limits, the source is proposing to use an activated carbon (sorbent) injection system as a primary control option for mercury with a chemical injection system to be considered as a secondary control option (either in conjunction with the sorbent injection system or as a stand-alone mercury control system). As part of the sorbent injection system, the source proposes to construct and operate two sorbent storage silos. The appropriate applicable requirements for these storage silos have been incorporated into the permit.

Public Service Company's (PSCo's) Pawnee Station is co-located with the Manchief Generating Station. Since the two facilities are located on contiguous and adjacent property, belong to the same industrial grouping (first two digits of the SIC code are the same) and are under common control (via a power purchase agreement with PSCo), they are considered a single stationary source for purposes of major stationary source new source review and Title V operating permit applicability. A separate Title V operating permit was issued for the Manchief Generating Station (01OPMR236). In addition, Boral Material Technologies, Inc. (BMTI) conducts ash conditioning, handling and blending operations at Pawnee station. BMTI is considered a support facility for PSCo's Pawnee Station and as such is considered a single source with PSCo's Pawnee Station and subsequently BMTI is also considered a single source with Manchief Generating Station. A separate Title V permit was issued for BMTI Pawnee Station (03OPMR244).

This facility is located at 14940 County Road 24, near Brush in Morgan County. The area in which the plant operates is designated as attainment for all criteria pollutants.

There are no affected states within 50 miles of the plant. There are no Federal Class I designated areas within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to more appropriately identify the **potential to emit (PTE)** of both criteria and hazardous air pollutants. Emissions (in tons/yr) at the facility are as follows:

Emission Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	Pb[1]	HAPS
PSCo – Pawnee Station (96OPMR129)								
Main Boiler (Unit 1)	2,341.5	2,154.2	28,098.6	10,771.1	725	87	0.61	See Page 26
Aux. Boiler	0.7	0.7	0.2	35.4	29.7	1.9		
Coal Handling (fugitives)	35.84	8.7						
Coal Handling (point sources)	15.3	6.8						
Ash Handling (fugitives)	19.66	7.08						
Haul Roads (fugitives)	47.9	12.2						
Ash Silo	2.13	2.13						
Soda Ash	0.007	0.007						
Cooling Tower	36.5	36.5				2.6		
Sorbent Silos	0.38	0.38						
PSCo Total Emissions	**2,499.9**	**2,228.7**	**28,098.8**	**10,806.5**	**754.7**	**91.5**	**0.61**	**97.33**
BMTI – Pawnee Station (03OPMR244)								
Fly Ash Conditioning System/MACS Bldg.	4.23	2.69						Negl.
Fugitive Emissions	18.7	6.22						Negl.
BMTI Total Emissions	**22.93**	**8.91**						**Negl.**
Manchief Generating Station (01OPMR236)								
Turbine 1	66.2	48.6	3.5	396.7	153.7	21.9		See Page 26
Turbine 2	66.2	48.6	3.5	396.7	153.7	21.9		
Diesel Generator	0.3	0.3	1.0	15.4	4.2	0.4		
Water Bath Heater	0.3	0.3	0.02	3.9	3.3	0.2		
Manchief Total Emissions	**133.0**	**97.8**	**8.02**	**812.7**	**314.9**	**44.4**		**11.78**
FACILITY Total Emissions	**2,655.83**	**2,335.41**	**28,106.82**	**11,619.2**	**1,069.6**	**135.9**	**0.61**	**109.11**

[1]Lead (Pb) emissions are based on emission factors from AP-42, Section 1.1 (dated 9/98), Table 1.1-17.

Potential to emit used in the above table are based on the following information:

Criteria Pollutants

PSCo – Pawnee: Potential to emit for all emission units except the main boiler and the sorbent silos are based on permitted emission limitations. Potential to emit for NO_X, SO_2 and PM from the main boiler are based on regulatory limits (Reg 1 for SO_2 and PM (1.2 lb/mmBtu and 0.1 lb/mmBtu, respectively) and Acid Rain for NO_X (0.46 lb/mmBtu)), the design heat input rate and 8760 hours per year of operation. PM_{10} emissions from the main boiler are presumed to be 92% of PM emissions (per AP-42, Section 1.1 (dated 9/98), Table 1.1-6. VOC and CO emissions from the main boiler are based on AP-42 emission factors (Section 1.1, dated 9/98, Tables 1.1-3 and 1.1-19) and the permitted coal consumption limit. Potential to emit from the sorbent silos is based on requested emissions provided on the APEN received December 19, 2008. Note that for the auxiliary boiler, permitted emission limitations were not included in the permit for PM, PM_{10} and VOC, the potential to emit for those pollutants are based on the requested emissions from the APEN submitted June 28, 2002 (noted in the technical review document prepared for the original Title V permit for PSCo Pawnee Station).

BMTI – Pawnee: Potential to emit is based on permitted emission limitations.

Manchief: Potential to emit for the turbines, heater and starter engine are based on permitted emission limitations. Note that for the heater and starter engine, permitted emission limitations were not included in the permit for certain criteria pollutants (PM, PM_{10}, CO (engine only), SO_2 and VOC) because emissions were below the APEN reportable level. Emissions for those pollutants are shown in the above table and emissions are based on the permitted fuel consumption limit and AP-42 emission factors.

Hazardous Air Pollutants (HAP)

The potential to emit table on page 3 provides total HAPs for each operating permit. The breakdown of HAP emissions by individual HAP and emission unit is provided on page 26 of this document. HAP emissions, as shown in the table on page 26, are based on the following information:

PSCo – Pawnee: Potential to emit of HAPS were only determined for the main boiler, the auxiliary boiler and the cooling tower. HAPS were not estimated for the other emission units as HAPs were presumed to be negligible from these sources.

HAP emissions from the auxiliary boiler are based on AP-42 emission factors (for natural gas Section 1.4, dated 3/98, Tables 1.4-3 and 1.4-4 and for No. 2 fuel oil Section 1.3, dated 9/98, Tables 1.3-9 and 1.3-11) and the permitted fuel consumption limit. Note that at the permitted fuel limits for both fuels, hours of operation would exceed 8760 hours per year, so an adjusted fuel limit for No. 2 fuel oil was used.

Metal HAP emissions from the main boiler are based on AP-42 emission factors (Section 1.1, dated 9/98, Table 1.1-18) and the permitted coal consumption limit. Mercury emissions from the main boiler are based on the average projected mercury emissions that were used in the development of Colorado's Mercury Rule. HF and HCl emissions from the main boiler are based on the maximum emission factor, in units of lbs/ton, determined from reported HF and HCl emissions and coal consumption on several current APENS (2007, 2006 and 2004 data) and the permitted coal consumption limit.

Manchief: HAP emissions are based on AP-42 emission factors and the permitted fuel consumption limits.

Note that actual emissions are typically less than potential emissions and actual emissions from the PSCo sources are shown on page 27 of this document.

Compliance Assurance Monitoring (CAM) Requirements

The source addressed the applicability of the CAM requirements in their renewal application and is discussed further in this document under Section III – Discussion of Modifications Made, under "Source Requested Modifications".

MACT Requirements

Case-by-Case MACT - 112(j) (40 CFR Part 63 Subpart B §§ 63.50 thru 63.56)

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the "MACT hammer".

Owners or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline were required to submit a Part 1 application to revise the operating permit by May 15, 2002. The source submitted a notification indicating that Pawnee Station was a major source for HAPS, with equipment under the source category for industrial, commercial and institutional boilers and process heaters.

Since the EPA has signed off on final rules for all of the source categories, which were not promulgated by the deadline, the case-by-case MACT provisions in 112(j) no longer apply. Note that there is a possible exception to this, as discussed later in this document (see under industrial, commercial and institutional boiler and process heaters).

RICE MACT (40 CFR Part 63 Subpart ZZZZ)

The RICE MACT (40 CFR Part 63 Subpart ZZZZ) was signed as final on February 26, 2004 and was published in the Federal Register on June 15, 2004. An affected source under the RICE MACT is any existing, new or reconstructed stationary RICE with a site-rating of more than 500 hp.; however, only existing (commenced construction or reconstruction prior to December 19, 2002) 4-stroke rich burn (4SRB) engines with a site-rating of more than 500 hp were subject to requirements. There are several engines included in the insignificant activity list. One of these, an emergency generator, is greater than 500 hp and another, an emergency fire pump engine, could be greater than 500 hp (it is listed between 300 hp and 750 hp). The remaining engines are less than 500 hp. Since the emergency generator and fire pump are existing compression ignition engines they do not have to meet the requirements of Subparts A and ZZZZ, including the initial notification requirements as specified in 40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3).

In addition, revisions were made to the RICE MACT to address engines $\leq$ 500 hp at major sources and all size engines at area sources. These revisions were published in the Federal Register on January 18, 2008. Under these revisions, existing compression ignition (CI) engines, 2-stroke lean burn (2SLB) and 4-stroke lean burn (4SLB) engines were not subject to any requirements in either Subparts A or ZZZZ (40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3)). For purposes of the MACT, for engines $\leq$ 500 hp, located at a major source, existing means commenced construction or reconstruction before June 12, 2006. The remaining engines included in the insignificant activity list are considered existing and therefore are not subject to the MACT. Since the source has not indicated that any additional engines have been installed at the facility, the Division considers that there are no new engines and therefore, no engines subject to the RICE MACT.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was signed on February 26, 2004 and was published in the Federal Register on September 13, 2004. There are propane portable heaters included in the insignificant activity list in Appendix A of the permit. However, these units do not meet the definition of boiler or process heater specified in the rule (the definition of process heater excludes units used for comfort or space heat). Therefore the heaters included in the insignificant activity list would not be subject to the Boiler MACT requirements.

The auxiliary boiler, which is included in Section II of the permit uses only natural gas as fuel. Existing large gaseous fuel units are only subject to the initial notification requirements as specified in 40 CFR Part 63 Subpart DDDDD § 63.7506(b)(2). The initial notification for the auxiliary boiler was submitted on February 16, 2005, prior to the March 12, 2005 deadline.

As of July 30, 2007, the Boiler MACT was vacated; therefore, the provisions in 40 CFR Part 63 Subpart DDDDD are no longer in effect and enforceable. The vacatur of the Boiler MACT triggers the case-by-case MACT requirements in 112(j), referred to as the MACT hammer, since EPA failed to promulgate requirements for the industrial, commercial and institutional boilers and process heaters by the deadline. Under the 112(j) requirements (codified in 40 CFR Part 63 Subpart B §§ 63.50 through 63.56) sources are required to submit a 112(j) application by the specified deadline. As of this date, EPA has not set a deadline for submittal of 112(j) applications to address the vacatur of the Boiler MACT. Although this unit was only subject to initial notification requirements, the Division considers that a 112(j) application should be submitted for this unit. Therefore, the Division will include a requirement to submit a 112(j) application in the permit by the deadline set by the Division and/or EPA.

Gasoline Distribution MACTs

A 500 gallon aboveground gasoline tank is included in the insignificant activity list (listed as an insignificant activity because emissions are less than the APEN de minimis level per Reg 3, Part C, Section II.E.3.a). There are potential MACT standards that could apply to this operation: Gasoline Distribution (Stage I) – 40 CFR Part 63 Subpart R (final rule published in the Federal Register on December 14, 1994), Gasoline Dispensing Facilities – 40 CFR Part 63 Subpart CCCCCC (final rule published in the Federal Register on January 10, 2008) and Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities – 40 CFR Part 63 Subpart BBBBBB (final rule published in the Federal Register on January 10, 2008). Both of the rules published on January 10, 2008 only apply at area sources. Since this facility is a major source for HAPS, the requirements in those rules do not apply to the gasoline tank at this facility. The Gasoline Distribution (Stage I) MACT applies to bulk gasoline terminals and pipeline break-out stations. The gasoline dispensing equipment at this facility does not meet the definition of a bulk gasoline terminal or a pipeline break-out station. Therefore, none of the MACT requirements associated with gasoline distribution apply to the equipment at this facility.

Federal Clean Air Mercury Rule Requirements

The EPA published final rules to address mercury emissions from coal-fired electric steam generating units on March 15, 2005. These rules are referred to as the Clean Air Mercury Rule (CAMR), which required mercury standards for new and modified emission units and provided a trading program for existing units. Under this program, sources would be required to get a permit (application due date July 10, 2008) and to meet monitoring system requirements (install and conduct certification testing) by January 1, 2009.

However, on February 8, 2008 a DC Circuit Court vacated the CAMR regulations for both new and existing units. Therefore, the federal CAMR requirements are not in effect, as of the issuance of this renewal permit.

State Clean Air Mercury Rule Requirements

Although the Division did adopt provisions from the federal CAMR rule into our Colorado Regulation No. 6, Part A, the Division also adopted State-only mercury requirements in Colorado Regulation No. 6, Part B, Section VIII. As discussed above the provisions from the federal CAMR rule have been vacated and are no longer applicable. While the state-only mercury requirements rely in some part of the federal CAMR rule, there are emission limitations and permit requirements that do not rely on the federal rule and are still in effect. In addition, on November 20, 2008, the Colorado Air Quality Control Commissions (AQCC) adopted into Reg 6, Part B, Section VIII, the monitoring, recordkeeping and reporting requirements in the vacated CAMR rule. The revisions to Reg 6, Part B take effect on December 30, 2008.

To that end, beginning on January 1, 2012, Unit 1 is required to comply with either of the following standards on a 12-month rolling average basis (Colorado Regulation No. 6, Part B, Section VIII.C.1.a):

0.0174 lb/GWh **OR** 80 percent capture of inlet mercury

Unit 1 would be subject to more stringent mercury standards beginning January 1, 2018 as set forth in Colorado Regulation No. 6, Part B, Section VIII.C.1.c.

As specified in Colorado Regulation No. 6, Part B, Section VIII.D.2, a permit application for Unit 1 must be submitted by January 1, 2009 to incorporate the requirements of Colorado Regulation No. 6, Part B, Section VIII and the Division must issue a revised permit by January 1, 2010. As such the source submitted an application on December 19, 2008 to incorporate the mercury control requirements and the Division is including the appropriate requirements in the draft renewal permit. Note that the requirements that will be included in the permit are discussed further in this document under Section III – Discussion of Modifications Made, under “Source Requested Modifications”.

Regional Haze Requirements

The main boiler (Unit 1) at this facility is subject to the regional haze requirements for best available retrofit technology (BART) and as such a BART analysis was conducted and a permit has been issued to address the BART requirements. The BART requirements have been included in Colorado Construction Permit 07MR0111B, which was issued September 12, 2008.

The BART permit requires the installation of a lime spray dryer on Unit 1 and either the modification of the existing low NO_X burners and over-fire air system or the installation of new low NO_X burners and over-fire air system. In addition, the permit sets new emission limits for SO_2, NO_X and PM.

The BART permit specifies that PSCo shall demonstrate compliance with the BART emission limits as expeditiously as practicable, but in no event later than five years following EPA approval of the state implementation plan for regional haze that incorporates these BART requirements. Although the PM, SO_2 and NO_X requirements in the BART permit do not take effect until EPA approves the Regional Haze SIP and the BART permit does not require that a Title V permit application to incorporate the BART provisions be submitted until 12 months after startup of the SO_2 and NO_X control equipment, the provisions in the BART permit have been included in the renewal permit.

III. Discussion of Modifications Made

<u>Source Requested Modifications</u>

November 20, 2006 Renewal Application

The source did no request any changes in their November 20, 2006 renewal application, but did conduct a CAM analysis and submitted a CAM plan for the main boiler (Unit 1).

The CAM requirements apply to any emission unit that uses a control device to meet an emission limitation or standard and has pre-controlled emissions above the major source level. There are several emission points at the facility that could potentially be subject to the CAM requirements. The source provided information regarding the applicability of the CAM requirements to the emission units at the facility as discussed below.

<u>Emission sources with no emission limitations</u>

All of the emission sources at this facility that are included in Section II of the permit have emission limitations.

<u>Emission sources with emission limitations</u>

No control device

The source identified the following sources/activities as units with no controls and therefore not subject to the CAM requirements: the auxiliary boiler, fugitive emissions from coal handling and storage, fugitive emissions from ash handling and disposal and fugitive emissions from vehicle traffic on paved and unpaved roads. The Division agrees that the auxiliary boiler and fugitive emissions from coal handling do not utilize any control devices to meet their emission limitations. However, the permit requires that water be sprayed on the ash pit as necessary to minimize fugitive emissions and that all active unpaved haul roads be watered daily to reduce visible emissions. The use of water to reduce fugitive or visible emissions can certainly be considered a control measure used to reduce emissions and meet emission limitations. However, the Division does not think that water sprays meet the definition of control equipment. The preamble to the CAM rule provides more insight into the control technology definition and provides the following (from October 22, 1997 Federal Register, page 54912, 3rd column, under *control devices criterion*)

> The final rule provides a definition of “control device” that reflects the focus of Part 64 on those types of control devices that are usually considered as “add-on” controls.” This definition does not encompass all conceivable control approaches but rather those types of control devices that may be prone to upset and malfunction, and that are most likely to benefit from monitoring of critical parameters to assure that they continue to function properly. In addition, a regulatory obligation to monitor control devices is appropriate because these devices generally are not a part of the source’s process and may not be watched as closely as devices that have a direct bearing on the efficiency or productivity of the source.

The Division considers that the use of water sprays to reduce fugitive and/or visible emissions is not considered an add-on control device and is not the type of device that would benefit from monitoring critical parameters. Therefore, the Division agrees that based on the specific provisions in the CAM requirements that fugitive emissions from ash handling and disposal and vehicle traffic on haul roads are uncontrolled activities. Therefore, the Division considers that the CAM requirements do not apply to fugitive emissions from ash handling and disposal and vehicle traffic on haul roads.

Pre-control emissions below the major source level

The source identified the following sources/activities as units with pre-controlled emissions below the major source level and therefore not subject to CAM: coal handling system (point sources), the ash silo, the soda ash handling system and the cooling tower. The Division’s analysis of the applicability of CAM to these units is as follows:

<u>cooling water tower</u> – the cooling water tower is equipped with drift eliminators which reduce drift to 0.001%. Without the drift eliminators, uncontrolled PM and PM_{10} emissions from the cooling water tower would exceed the major source level. However, the Division considers that the drift eliminators are not considered a control device. In 40 CFR Part 64, § 64.1, control device means “equipment other than inherent process equipment that is used to destroy or remove pollutants prior to discharge to the atmosphere…For purposes of this part, a control device does not include passive control measures, that act to prevent pollutants from forming, such as the use of seals, lids or roofs to prevent the release of pollutants”. The Division considers that the drift eliminators are considered inherent process equipment and are passive devices and as such are not considered control equipment. Therefore, the Division considers that the CAM requirements do not apply to the cooling water tower.

Soda ash handling system: The Division agrees that using the uncontrolled emission factor and permitted processing rate that emissions from the soda ash handling system are below the major source level.

Ash silo: According the technical review document prepared for the original Title V permit (issued January 1, 2003), the bin vent fan for the ash silo exhausts through the boiler baghouse. Therefore, the ash silo shares a control device with the baghouse. Particulate matter emissions from the ash silo are estimated separately using the emission factors and assumed control efficiencies and are much less than particulate matter emissions from the boiler itself. As discussed below, the boiler baghouse is subject to CAM and the source has submitted a CAM plan based on the boiler operation. Therefore, nothing further is required to address the emissions from ash silo operations.

Coal handling (conveying and crusher): As discussed in the technical review document prepared for the original Title V permit, the emission limits that were set for the coal handling system do not take credit for controls such as the baghouses (transfer tower and crusher), the water sprays or the enclosures (conveyors are covered); except that some credit is taken for the crusher enclosures. Permitted emissions from coal handling (except the crusher) are based on emission factors for conveying that rely on wind speed and the moisture content of the coal. The calculations were performed using a high wind speed (8.7 mph), which the Division considers does not take credit for covered conveyors. At the permitted coal processing rate, uncontrolled emissions from the crushers are below the major source level, therefore, CAM does not apply to the coal handling system.

Although not addressed in the renewal application, the Division made the following determination regarding the applicability of CAM to the proposed new sorbent silos as follows:

Requested emissions from these emission units are based on assumptions for grain loading specifications and air flow. Therefore estimating uncontrolled emissions are difficult. Based on the requested emission rate, the associated control devices would have to have a control efficiency of greater than 99.8% (for one silo alone) in order to have uncontrolled emissions below the significance level. Although typically silos have been considered to have control efficiency of 99.9%, the Division considers that based on the low requested throughput, uncontrolled emissions are unlikely to exceed the major source level. Using the AP-42 emission factor of 1.5 lbs/ton for lime manufacturing, product loading, open truck (AP-42 (dated 2/98), Section 11.17, Table 11.17-4), which the Division considers to be conservative, uncontrolled emissions are well below the major source level. In fact, based on the requested throughput limit, it would require an emission factor of 350 lbs/ton to put uncontrolled emissions above the major source level. Therefore, the Division considers that the sorbent silos are not subject to the CAM requirements.

Pre-control emissions above the major source level

The source identified the main boiler (Unit 1) as being subject to CAM, since a control device is required to meet the PM emission limitations. Unit 1 is subject to PM, SO_2 and NO_X emission limitations. Controlled emissions of these pollutants exceed the major source level and this unit uses emission controls (baghouse for PM and low NO_X burners with over-fire air for NO_X) to meet its PM and NO_X emission limitations. Therefore, Unit 1 is potentially subject to the CAM requirements.

Unit 1 is subject to SO_2 and NO_X emission limitations under the Acid Rain Program (Section III of the current permit). Pursuant to 40 CFR Part 64 § 64.2(b)(1)(iii), the CAM requirements do not apply to Acid Rain Program emission limitations.

Unit 1 is subject to short-term SO_2 and NO_X emission limitations (both on 3-hr rolling average). The current Title V permit requires that the source use continuous emission monitoring systems to demonstrate compliance with the SO_2 and NO_X emission limitations. Therefore, since the Title V permit specifies a continuous compliance method for these emission limitations, the CAM requirements do not apply in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(iv).

CAM does apply to the Unit 1 with respect to the PM emission limitations. Note that although the unit is subject to opacity limits, they are not emission limitations subject to CAM requirements. The source submitted a CAM plan with their renewal application. In their CAM plan, the source proposed visible emissions, pressure differential and preventative maintenance as indicators. For visible emissions, excursions are identified as an opacity value exceeding 15% for one minute or more and any long term increase in opacity of 10% above baseline levels for normal operation. For pressure differential, an excursion is defined as an increase in differential pressure of 3 inches of water column or greater from normal baseline levels accompanied by a sustained increase in opacity over 10%.

The Division has reviewed the CAM plan submitted and while we accept the plan in part, we consider that changes to the plan are necessary. The Division considers that the following changes are necessary to the plan.

Visible Emissions

The Division accepts the indicator range of 15% opacity for one minute or more and will include this in the permit.

The second indicator range of “a long term increase in opacity emissions from baseline conditions during normal operations to opacity emissions greater than 10% over an extended period of time” is non-specific as to the time frame and it is not clear that the 10% opacity represents an acceptable opacity level as an indicator range. Therefore, the Division will include as CAM, the compliance provisions required for new (constructed after February 28, 2005) electric utility steam generating units subject to

PM fuel based emission limitations (i.e. units of lb/mmBtu) in 40 CFR Part 60 Subpart Da, since such monitoring represents presumptively acceptable monitoring in accordance with the provisions in 40 CFR Part 64 § 64.4(b)(1)(4). The compliance provisions specified in Subpart Da require that a baseline opacity level be set during a performance test and then requires monitoring of opacity emissions on a 24-hour average. If the opacity 24-hour average exceeds the baseline level, then the source must investigate and take the appropriate corrective action. Note that as provided for in 40 CFR Part 60 Subpart Da § 60.48Da(o)(2)(iv), periods of startup, shutdown and malfunction may be excluded from the 24-hour average.

The baseline opacity level determined under the provisions of NSPS Subpart Da specify that 2.5% opacity be added to the average opacity determined during the performance test, although the baseline opacity level can be no lower than 5% opacity. Since the units required to conduct this monitoring under NSPS Subpart Da are subject to more stringent particulate matter limitations, the opacity add-on will be based on the results of the performance test. However, in no case would the baseline opacity be set lower than 5%.

Pressure Differential

The source has indicated that an excursion would be "an increase in differential pressure across a baghouse of 3 inches of water column or greater from the unit's normal specific operating load during normal operating conditions, as well as a sustained increase in opacity greater than 10%". While the proposed language does not specifically define the pressure differential for the "unit's normal specific operating load", in their justification the source indicates that the normal pressure differential varies based on the operating load. While the Division understands that it may be difficult to identify specific ranges since the appropriate pressure differential varies depending on the load, failure to identify the specific range makes it difficult for the Division to independently determine whether an excursion has occurred. In addition, as indicated in the CAM plan, an increase or decrease in the pressure differential from the normal level at a specific operating load is not necessarily considered an indicator of decreased baghouse performance by itself. However, an increase or decrease in the pressure differential from the normal level, accompanied by a sustained increase in opacity is an indication of potential baghouse problems.

Since the normal pressure differential is specific to load and cannot be easily defined and because pressure differential by itself is not necessarily an indicator of potential problems with the baghouse, the Division will not include pressure differential in the CAM plan as an indicator. In accordance with 40 CFR Part 64 § 64.4(b)(4), presumptive CAM is monitoring included for standards that are exempt from CAM (i.e. NSPS standards promulgated after November 15, 1990) to the extent that such monitoring is applicable to the performance of the control device (and associated capture system). As discussed previously, the Division has revised the source's CAM plan to require that visible emissions be monitored in accordance with the monitoring required for new boilers subject to 40 CFR Part 60 Subpart Da. The emission limitations and monitoring for new boilers were published as final in the February 27, 2006 Federal Register, although changes to the monitoring requirements were published as final in the Federal Register on June 13, 2007. New boilers subject to the revised PM emissions limits in 40 CFR Part 60 Subpart Da are required to monitor compliance with the PM emission limitation using their COM by establishing a baseline opacity. Therefore, the baseline opacity monitoring that the Division is including in the CAM plan represents presumptive CAM and the Division does not believe that it is necessary to include pressure differential as an additional indicator.

It should be noted that new sources subject to the NSPS Da PM limitation are also required to conduct annual performance tests. While the Division has not included annual performance testing in the permit as part of the CAM plan, the Division does require performance tests as periodic monitoring to demonstrate compliance with the PM limitations. Frequency of testing is annual, unless the results of the testing are much lower than the standard, then less frequent testing is allowed.

Preventative Maintenance

The preventative maintenance that the source has proposed is a monthly review of historic minute opacity data and that based on this review, if warranted, repairs will be initiated to internal and/or external baghouse components. It is not clear what specifically the source would be looking for in the historic minute opacity data and what would trigger any repairs. The Division considers that preventative maintenance is important to the proper operation of the baghouse, therefore, the Division has revised the preventative maintenance indicator to require annual internal inspections of the baghouse. Although the CAM plans for other PSCo facilities specify semi-annual internal baghouse inspections, PSCo provided information indicating that at this facility semi-annual internal inspections would be burdensome. The Division has however, included a requirement to conduct an additional internal baghouse inspection in the event of an opacity excursion, although no more than two internal baghouse inspections are required in any calendar year.

In general, the CAM plan has been included in Appendix H of the permit as submitted, except that the corrections indicated above have been made to the plan and some language has been omitted, revised or relocated in order to streamline the plan.

December 19, 2008 Application for Permit Modification

The source submitted an application on December 19, 2008 to incorporate the mercury (Hg) control requirements in Colorado Regulation No. 6, Part B, Section VIII into their permit. In accordance with the requirements in Reg 6, Part B, Section VIII.D.2 an application was to be submitted for the Pawnee facility by January 1, 2009 and a revised permit shall be issued by January 1, 2010. Since the renewal application had been received for this facility the Hg requirements are being directly incorporated into the renewal permit.

Reg 6, Part B, Section VIII Hg Requirements

Reg 6, Part B, Section VIII.D.4 states that all permit applications shall include the following:

- a statement indicating that the Hg budget units in the State under the control of the owner or operator shall comply with the emission standards and other requirements of this Section VIII
- a detailed compliance plan for each applicable emission standard, or schedule for achieving compliance with that standard, including monitoring and reporting, and
- a description of the assumptions on which the plan is based.

In their application, the source indicated that they proposed to use sorbent injection using a halogenated activated carbon to reduce Hg emissions and that they expected this control method would also allow the unit to meet both the 2012 and 2018 Hg emission limits. The source also proposed to use chemical injection, either by itself or in conjunction with a sorbent injection system. The source is in the process of evaluation this technology further but believe that it could be effective in meeting the 2012 emission limitation. The chemical injection system sprays chemicals such as calcium chloride or calcium bromide on the coal as it is being conveyed to the bunkers or fed into the boiler. During the combustion process, these chemicals oxidize mercury so it can be collected in the baghouse.

Reg 6, Part B, Section VIII.D.1, specifies that the emission standards, low emitter provisions, and permitting, monitoring and enforceability requirements shall be incorporated into the permit for each subject Hg Budget unit. However, the provisions in Section VIII.D.5 specify that all permits shall include all applicable requirements, including requirements to comply with the emission standards in Section VIII.C and requirements to comply with the permitting and monitoring requirements of Sections VIII.D and VIII.E and 40 CFR Part 75 (this section does not require that the enforceability requirements be included). These sections appear to contradict each other; however, the Division has determined that it is appropriate to include the following requirements in the permit:

- the Hg emission limitations in Section VIII.C.1.a

  Note that since the source indicated in their December 19, 2008 application that they would meet the output limit only the outlet limit has been included in the permit.

- the monitoring requirements in Section VIII.E

- the enforceability requirements in Section VIII.F

In general the Division included the requirements in the permit that were identified in Section VIII.D.1, with the following exceptions.

The Division did not include the low emitter provisions since this unit is not a low emitter and is specifically required to meet the Hg emission limits in Section VIII.C.1.a. Along those same lines the Division did not include the reporting requirements for low emitters specified in Section VIII.E.3.c**.**

In addition, it is not clear which parts of the permitting section in the regulation would be relevant to include in a permit, since this section merely sets out the requirements for what is to be included in the permit application and the permit and the deadline for source's to submit permit applications and the Division to issue permits. Therefore, the Division did not include any of the permitting requirements specified in Section VIII.D.

Finally, Section VIII.E.4 specifies the submittal of a monitoring plan for Division approval for any units that are either demonstrating compliance with the percent capture limits or the outlet emission standards. The source submitted a monitoring plan that included the elements in Section VIII.E.4.b for the meeting the outlet standards. Since the plan has been submitted, the Division considers that the requirements in this Section VIII.E.4 have been fulfilled and therefore, will not be included in the permit. However, the Division will include a requirement in the permit to follow the Division-approved monitoring plan.

Sorbent Injection Silos

In addition, since the source has proposed a sorbent injection system, which requires sorbent storage silos, the Division has included the appropriate applicable requirements for the storage silos into Section II.5 of the renwal permit as a combined construction/operating permit as provided for in Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7. These requirements include the following:

- Construction of this source must commence within 18 months of initial approval permit issuance date or within 18 months of date on which such construction or activity was scheduled to commence as stated in the application (Reg 3, Part B, Section III.g.4.a.(i) thru (ii)).
- Within 180 days after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division (Reg 3, Part B, Section III.G.2)

  Note that the Division considers that the first semi-annual monitoring and permit deviation report submitted after the units commence operation will serve as the self-certifcation.
- The permittee shall notify the Division, in writing, thirty (30) days prior to startup (Reg 3, Part B, Section III.G.1).

  Note that by policy the Division currently asks that the startup notice be submitted within 30 days after the units commence operation.
- 20% opacity (Regulation No. 1, Section II.A.1)

Based on engineering judgment, the Division has not included the 30% opacity requirement for startup, process modification and adjustment of control equipment (Reg 1, Section II.A.4) for the following reasons: 1) startup is instantaneous (begin loading or unloading); 2) process modifications are unlikely since the process of loading and unloading is straightforward and if modifications were to occur, they could not occur while the unit is in operation (i.e. loading or unloading) and 3) the control equipment cannot be adjusted while loading or unloading is occurring.

- APEN reporting (Reg 3, Part A, Section II)

  The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

- Sorbent processing not to exceed 560 tons/yr (based on information provided in December 19, 2008 permit application)
- PM emissions not to exceed 0.38 tons/yr (based on requested emissions provided in the APEN received on December 19, 2008)
- PM_{10} emissions not to exceed 0.38 tons/yr (based on requested emissions provided in the APEN received on December 19, 2008)

The Division determined that neither the Regulation No. 1 (Section III.C.1) nor the Regulation No. 6 (Part B, Section III.C, including opacity) particulate matter standards were applicable to the sorbent silos. The Division does not consider these to be manufacturing processes since the sorbent is used to control Hg emissions from Unit 1.

Emission Factors

Emissions from the sorbent silos are based on the assumed baghouse rating of 0.01 gr/dscf, the rated air flow of 500 dscfm and 8,760 hrs/yr of operation. The emission rate in lbs/hr from each of the silos was determined as follows:

$$\text{Emissions (PM and PM}_{10}\text{)} = \frac{0.01 \text{ gr/dscf} \times 500 \text{ dscfm} \times 60 \text{ min/hr}}{7{,}000 \text{ gr/lb}} = 0.043 \text{ lbs/hr}$$

May 7, 2009 Comments on the Draft Permit and Technical Review Document

Main Boiler (Unit 1) and Auxiliary Boiler

In their comments, the source indicated that the main boiler (Unit 1) and the auxiliary boiler are no longer capable of burning No. 2 fuel oil and requested that language related to No. 2 fuel oil burning be removed. To that end the Division revised the description of the auxiliary boiler in Section I, Condition 1.1 and the descriptions of the main boiler and auxiliary boiler in the tables in Section I, Condition 6.1 (“old” Condition

5.1) and Appendices B and C. In addition, Section II.2 (Unit 1) was revised to remove references to No. 2 fuel oil. Finally, Section II.3 (Auxiliary Boiler) was revised to remove references to No. 2 fuel oil and permit conditions 3.4, 3.5, 3.6.2 and 3.7.2, which are related to No. 2 fuel oil use. The source submitted a revised APEN on May 28, 2009, to reflect that natural gas will be the only fuel used. Emissions from PM, PM_{10}, SO_2 and VOC, when burning natural gas are below the APEN de minimis level, therefore, emission limitations for PM, PM_{10}, SO_2 and VOC have not been included in the permit.

Section II, Condition 5.4

The phrase "transfer tower" was replaced with "transfer tower/tripper deck" to more appropriately identify one of the baghouses referenced in this permit condition.

Appendix A – Insignificant Activity List

In their comments on the draft permit (submitted on May 7, 2009), the source requested the following changes to the insignificant activity list.

The following changes were made to the list under the category of "chemical storage tanks or containers < 500 gal":

- The following equipment was removed:
    - R.O. Acid dilution feed tank (200 gal)
    - R.O. Scale inhibitor feed tank (180 gal)
- The following equipment was added:
    - R.O. Acid feed tank
    - R.O. Anti-scalant feed tank
    - R.O. Sodium bisulfate feed tank
    - R.O. Caustic feed tank
    - Bleach feedwater tank
    - Sewage bleach feed tank

The category for "fuel storage and dispensing equipment < 400 gal/day" was revised to indicate there are two 1,000 gal unleaded gasoline storage tanks.

Under the category for "storage tanks with annual throughput less than 400,000 gal/yr and meeting content specifications", the following changes were made:

- Removed the 325,000 gal No. 2 fuel oil storage tank
- Revised to indicate there is a 10,000 gal above ground diesel storage tank in addition to a 10,000 gal underground diesel storage tank

Added the facility's warehouse and water treatment buildings under the category for "chemical storage areas < 5,000 gal".

The description of the holding and evaporation ponds under the category "emissions of air pollutants that are not criteria or non-criteria reportable pollutants" was corrected to indicate they are located on the east and south sides of the facility.

Under the category for "not sources of emissions" the following changes were made:

- Corrected the description of the seed tank to indicate it is 600 gal, rather than 400 gal
- Added the following equipment:
  - Feed tank (4,500 gal)
  - Brine tank (16,000 gal)
  - Bleach tank (16,000 gal)
  - Tolyltriazole tank (1,000 gal)
  - Scale inhibitor tank (1,000 gal)

The lime silo used in the water treatment process was added under the category "units with emissions less than APEN de minimis – criteria pollutants". The source indicated that emissions are estimated to be 0.5 tons/yr of PM and PM_{10}.

The source indicated in an e-mail received May 14, 2009 that the fire pump engine is rated at 240 hp, therefore, the Division corrected this entry under the category "stationary internal combustion engines – limited size or hours".

Other Modifications

In addition to the modifications requested by the source, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Pawnee Station Operating Permit with the source's requested modifications. These changes are as follows:

General

- The Reg 3 citations were revised throughout the permit, as necessary, based on the recent revisions made to Reg 3.

Page Following Cover Page

- Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

- Changed the responsible official.

Section I - General Activities and Summary

- Revised the description under Condition 1.1 to address the three separate operating permits issued for the facility and to indicate that the auxiliary boiler can burn either natural gas or No. 2 fuel oil.

- Removed construction permit 12MR093-2 from the list in Condition 1.3.

- Section V, Conditions 3.d and 3.g (last paragraph) were added as state-only requirements in Condition 1.4. Note that Section V, Condition 3.d (affirmative defense provisions for excess emissions during malfunctions) is state-only until approved by EPA in the SIP.

- Made minor revisions to the language in Condition 3 (prevention of significant deterioration) to be more consistent with other permits.

- Added a column to the Table in “old” Condition 5.1 for the startup date of the equipment. In addition, added “Unit 1” to the description of Boiler 1 and “auxiliary boiler” to the description of Boiler 2 to more appropriately identify the units.

- Added “new” Condition 5.1 for compliance assurance monitoring (CAM) requirements.

Section II.1 – Main Boiler (Unit 1), Coal Firing

- Added “Unit 1” to the table header to more clearly identify the unit.

- References to fuel usage or fuel sampling were replaced with coal usage or coal sampling.

- The second paragraph in Condition 1.3 (violations of the SO_2 emission standard shall not be considered as arising from an “upset” condition) was removed. This paragraph was included incorrectly in the Title V permit. In the underlying construction permit, this paragraph included the phrase “due to a lack of coal of suitable quality" after the word "standard"; however that phrase was not included in the Title V permit. Lack of coal of suitable quality would not qualify as a malfunction, as defined in the Common Provisions language; therefore, the Division is removing this language, rather than restoring it to the language included in the construction permit.

- Revised Condition 1.7 (fuel sampling) to remove lead.

- Revised the language in Condition 1.1.2 to specify that the performance tests shall be used to set the baseline opacity for the CAM plan and specified how the baseline opacity shall be determined.

- Removed the last sentence from Condition 1.14. This condition already refers the reader to Section III for Acid Rain provisions and this last sentence is not necessary.

Section II.3 – Auxiliary Boiler

- Based on EPA's response to a petition on another Title V operating permit, minor language changes were made to various permit conditions (both in the table and the text) to clarify that only natural gas or No. 2 fuel oil is used as fuel for permit conditions that rely on fuel restriction for the compliance demonstration.

- Added a requirement to submit a case-by-case MACT analysis.

Section II.4 – Particulate Matter Emissions – Fugitive Emissions

- Removed the language from Condition 4.1 that indicates that the emissions provided in the table are included for information purposes only. These emission rates are used in the modeling analysis and are considered limitations. Although the Division does consider that if the materials handling limits are met and the control measures are followed, then the source is in compliance with the emission limitations. To that effect the Division has revised the language in Condition 4.1.

- Based on comments received during the public comment period, the following phrase was added to Condition 4.2.1 "[t]he 20% opacity, no off-property transport, and nuisance emission limitations are guidelines and not enforceable standards and no person shall be cited for violation thereof pursuant to C.R.S. 25-7-115."

Section II.5 – Particulate Matter Emissions – Point Sources

- Corrected the PM limit for the coal handling system (P001). The technical review document prepared for the original Title V permit (issued January 1, 2003) indicated that permitted PM emissions from coal handling was set at 15.4 tons/yr; however, a limit of 15.3 tons/yr was included in the permit.

- The references to “Colorado Construction Permit 12MR093-2” were replaced with “Colorado Construction Permit 12MR093-1”. As discussed in the technical review document for the original Title V permit (issued January 1, 2003), there were three construction permits issued for coal handling: 12MR093-1 (fugitive emissions), 12MR093-2 (crusher) and 12MR093-2 (transfer tower). The Division intended that the fugitive emission sources be addressed on permit 12MR093-1 and that point sources be addressed on 12MR093-2 and that permit 12MR093-3 would be cancelled. However, the Division’s database is indicating that both permits 12MR093-2 and 12MR093-3 are cancelled. Since the source reports emissions from coal handling (both fugitive and point source emissions) on one APEN, including all coal handling on one permit is more appropriate.

- Removed Condition 5.8.1 (initial performance test requirement) since the initial performance test was conducted. The language in Condition 5.8.2 was incorporated into Condition 5.8.

- Based on comments received during the public comment period, the Division included requirements to conduct annual Method 9 visible emission observations on the transfer tower/tripper deck and crusher baghouses.

<u>Section II.7 – NSPS General Provisions</u>

- Removed the reference to Colorado Regulation No. 1, Section VI.B.4.a.(iv) in the citation for Condition 7.1. The good practices language in Colorado Regulation No. 1 has been removed.

<u>Section II.8 – Particulate Matter Emission Periodic Monitoring Requirements</u>

- Removed the language in Condition 8.1 regarding the COMS and opacity spikes. The Division considers that with the CAM plan requirements this language is no longer necessary.

- Revised the stack testing language in Condition 8.2 to clarify the frequency of testing. The language in the permit addresses testing within the expected five-year permit term. The permit terms may be extended, provided a timely and complete renewal application has been submitted. For the most part, complete and timely renewal applications have been submitted and the term of the permits have been extended beyond the originally anticipated five-year permit term. Therefore, the language has been revised to set specific deadlines for testing, which more appropriately reflects the Division’s intent to require testing for particulate matter at a minimum of every five years. To that end, the language regarding waiving testing within the last two years of the permit term, in the event that annual testing was triggered, has been removed. In general, the results of the initial tests have not been above 75% of the standard and annual testing has not been triggered. Therefore, the Division considers that the language is not necessary.

Section II.9 – Continuous Emissions Monitoring System Requirements

- Removed the phrase "and the traceability protocols of Appendix H" from Condition 9.3.2, since Appendix H of the current version of 40 CFR Part 75 is "reserved". Note that Condition 9.3.1 specifies that the continuous emission monitoring systems are subject to the requirements of 40 CFR Part 75 and that would include any applicable appendices, regardless of whether or not they are specifically called out in this condition.

- Based on citizen comments on another Title V permit, Condition 9.4.3 (monitoring opacity when the COM is down) was removed from the permit.

Condition 11 – Lead Periodic Monitoring

- Revised Condition 11.2 to indicate that lead emissions would be based on the annual TRI Report.

"New" Section II.14 – Regional Haze Requirements

As discussed previously in this document, a construction permit (07MR0111B) was issued on September 12, 2008 to address the regional haze requirements for BART. The appropriate applicable requirements from this permit have been included in the permit as follows:

- Control technology requirements (condition 1). This condition will be included in the permit.

- CEMS requirements (condition 2). The CEMS requirements are already included in the Title V permit.

- Emission limitations (conditions 3a, b & c). The SO_2, NO_X and PM emission limitations will be included in the permit.

- Compliance schedule (condition 3.d). This condition will be included in the permit.

- Submittal of Title V permit application (condition 4). Since the conditions of the BART permit are being incorporated into the Title V permit at this time, this condition is no longer relevant and won't be included in the permit.

- O & M plan requirements (condition 5). The appropriate monitoring requirements will be included in the Title V permit; therefore, this requirement will not be included in the permit.

- Demonstrating compliance with permit conditions (condition 6). The Division considers that the Responsible Official certification submitted in conjunction with the first semi-annual monitoring and permit deviation report submitted after the compliance date for the BART requirements will serve as the compliance demonstration; therefore, this requirement will not be included in the permit.

- General terms and conditions (condition 7). This condition addresses the applicability of general terms and conditions in the construction permit. They are not relevant to the title V permit and will not be include in this permit.

- Reporting requirements (condition 8). This condition will be included in the permit.

<u>Condition 12 – Coal Sampling Requirements</u>

- Since the permit no longer requires that the lead emission calculations use the lead content of the coal, the requirement to sample coal for the lead content in Condition 14.1 has been removed.

<u>Section III – Acid Rain Requirements</u>

- Revised the Designated Representative.

- Revised the table in Section 2 to include calendar years corresponding to the relevant permit term for the renewal.

- Revised the NO_X limit in the table in Section 2. The source had elected to comply with the Phase I NO_X requirements in 1997. Beginning in January, the source was subject to the Phase II NO_X requirements. Therefore, those limits have been included in the permit.

- Removed Section 3, since the NO_X early election expired beginning in January 2008.

- Minor changes were made to the standard requirements (Section 4), based on changes made to 40 CFR Part 72 § 72.9.

- Removed the requirement in Section 5 to submit a copy of any revised certificate of representation to the Division. Submitting a copy of the certificate of representation to the permitting authority is not required under the regulations.

- Removed the requirement to submit the annual reports and compliance certifications in Section 5. As a result of revisions to the Acid Rain Program made with the Clean Air Interstate Rule (final published in the Federal Register on May 12, 2005), annual compliance certifications are no longer required, beginning in 2006. Note that although the CAIR rule was vacated (July 2008), this revision was unrelated to the CAIR rule and it is expected that these changes will not be affected by the CAIR vacatur. Note that in December 2008, the vacatur of the CAIR rule was over-turned.

Section IV – Permit Shield

- The citation for the permit shield has been revised to reflect revisions and restructuring of Reg 3, to correct the citation of Reg 3, Part C, Section XIII to XIII.B and to remove Reg 3, Part C, Section V.C.1.b and C.R.S. § 25-7-111(2)(I) since they don't address the permit shield.

Section V – General Conditions

- Added a version date to the General Conditions.

- Revisions were made to the Common Provisions Regulation (general condition 3), effective September 30, 2002 and December 15, 2006 (effective March 4, 2007). The appropriate revisions were made to the language in the permit. The September 30, 2002 revisions were minor in nature. The December 15, 2006 revisions replaced the upset provisions with the affirmative defense provisions for excess emissions during malfunctions. Note that these provisions for malfunctions are state-only enforceable until approved by EPA into Colorado's state implementation plan (SIP).

- Replaced the reference to "upset" in Condition 5 (emergency provisions) and 21 (prompt deviation reporting) with "malfunction".

- The title for Condition 6 was changed from "Emission Standards for Asbestos" to "Emission Controls for Asbestos" and in the text the phrase "emission standards for asbestos" was changed to "asbestos control".

- General Condition No. 21 (prompt deviation reporting) was revised to include the definition of prompt in 40 CFR Part 71.

- Replaced the phrase "enhanced monitoring" with "compliance assurance monitoring" in General Condition No. 22.d.

Appendices

- Created a category under Appendix A – Insignificant Activities for non-road engines. All but the fire pump engine listed under the "stationary internal combustion engine" category are non-road engines.

- Replaced Appendices B and C with the latest versions. In addition replace "Unit 2" with "Auxiliary Boiler" to the description of B002 to more appropriately identify the unit.

- Changed the mailing address for EPA in Appendix D. Removed the Acid Rain addresses in Appendix D, since annual certification is no longer required and submittal of quarterly reports/certifications is done electronically.

- Added a column labeled "Type of Revision" to the Table in Appendix F.

Total Facility HAP Emissions (tons/yr)

Emission Unit	acetaldehyde	acrolein	BTEX	formaldehyde	chloroform	Hexane	HCL	HF	Mercury	Metals	Total
Manchief Equipment (01OPMR236)											
Turbine 1	0.243	0.0389	1.25	4.32							5.85
Turbine 2	0.243	0.0389	1.25	4.32							5.85
Starter Engine	1.24E-04	3.89E-05	6.17E-03	3.89E-04							6.72E-03
Heater			2.14E-04	2.92E-03		7.01E-02				1.79E-04	7.34E-02
PSCo Pawnee Equipment (96OPMR129)											
Main boiler							20.3	53.65	0.18	19.93	94.06
Auxiliary boiler			1.94E-03	2.65E-02		6.36E-01				7.42E-04	0.67
Cooling Tower					2.6						2.60
Facility Total	0.49	0.08	2.51	8.67	2.60	0.71	20.30	53.65	0.18	19.93	109.11
PSCo Total				0.03	2.60	0.64	20.30	53.65	0.18	19.93	97.33
Manchief Total	0.49	0.08	2.51	8.64		0.07					11.78

Manchief Generating Station HAPS are based on AP-42 emission factors and permitted fuel consumption limits

PSCo Pawnee HAPS are based on the following. Auxiliary boiler: AP-42 emission factors and fuel consumption limit requested in APEN submitted May 28, 2009. Cooling Tower: permitted VOC emission limits all VOC assumed to be chloroform. Main Boiler: Metals are based on AP-42 emission factors and permitted fuel consumption limit, HCl and HF based on emission factors determined using emissions and fuel consumption reported on APENS (using 2007, 2006 and 2004 data), and mercury emissions from average projected emissions used to support development of Colorado Mercury Rule.

PSCo Pawnee Actual Emissions (tons/yr)

Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPS
Main Blr (Unit 1)	132.6	122	14126.5	4415.2	598.5	71.2	61.36
Aux. Blr	0.003	0.003	0.0008	0.14	0.12	0.008	
Coal - fugitive	13.9	4.6					
Coal - pt source	3.4	1.2					
Ash - fugitive	6.6	2.4					
Ash - pt source (silo)	1.2	1.2					
Haul Roads - fug	33.3	8,5					
Soda Ash Silo	0.005	0.005					
Cooling Twr	22.5	22.5				2.5	0.12
Total	213.51	153.91	14,126.50	4,415.34	598.62	73.71	61.48
Total – Fugitive	53.80	15.50					
Total – Point Sources	159.71	146.91	14,126.50	4,415.34	598.62	73.71	61.48

Actual emissions from main boiler, coal handling and soda ash from APEN submitted 4/30/08 (2007 data)
Actual emissions from auxiliary boiler, haul roads and cooling tower from APEN submitted 4/9/07 (2006 data)
Actual emissions from ash handling from APEN submitted 4/19/05 (2004 data)
HAP emissions from cooling tower are chloroform
HAP emissions from main boiler consist of HCl, HF, manganese and nickel